UNITED STATES
SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

Form 10-K

(Mark One)

☒ **ANNUAL REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the fiscal year ended December 31, 2001

OR

☐ **TRANSITION REPORT PURSUANT TO SECTION 13 OR 15(d) OF THE SECURITIES EXCHANGE ACT OF 1934**

For the transition period from to

Commission file number 1-4874

Colorado Interstate Gas Company

(Exact name of registrant as specified in its charter)

Delaware	**84-0173305**
(State or other jurisdiction of incorporation or organization)	(I.R.S. Employer Identification No.)
El Paso Building **1001 Louisiana Street** **Houston, Texas**	**77002**
(Address of principal executive offices)	(Zip Code)

Registrant's telephone number, including area code: (713) 420-2600

Securities registered pursuant to Section 12(b) of the Act:

Title of each class	Name of each exchange on which registered
10% Senior Debentures, due 2005 6.85% Senior Debentures, due 2037	New York Stock Exchange

Securities registered pursuant to Section 12(g) of the Act: None

Indicate by check mark whether the Registrant (1) has filed all reports required to be filed by Section 13 or 15(d) of the Securities Exchange Act of 1934 during the preceding 12 months, and (2) has been subject to such filing requirements for the past 90 days. Yes ☑ No ☐

Indicate by check mark if disclosure of delinquent filers pursuant to Item 405 of Regulation S-K is not contained herein, and will not be contained, to the best of Registrant's knowledge, in definitive proxy or information statements incorporated by reference in Part III of this Form 10-K or any amendment to this Form 10-K. ☑

State the aggregate market value of the voting stock held by non-affiliates of the registrant: . . . None

Indicate the number of share outstanding at each of the registrant's classes of common stock, as of the latest practicable date.

Common Stock, no par value. Shares outstanding on March 28, 2002: 10

COLORADO INTERSTATE GAS COMPANY MEETS THE CONDITIONS OF GENERAL INSTRUCTION I(1)(a) AND (b) TO FORM 10-K AND IS THEREFORE FILING THIS REPORT WITH A REDUCED DISCLOSURE FORMAT AS PERMITTED BY SUCH INSTRUCTION.

Documents incorporated by reference: None

COLORADO INTERSTATE GAS COMPANY

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* We have not included a response to this item in this document since no response is required pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

Below is a list of terms that are common to our industry and used throughout this document:

/d	= per day	MBbls	= thousand barrels
BBtu	= billion British thermal units	Mcf	= thousand cubic feet
Bbl	= barrels	MMcf	= million cubic feet
Bcf	= billion cubic feet	MMcfe	= million cubic feet of gas equivalents

When we refer to natural gas and oil in "equivalents," we are doing so to compare quantities of oil with quantities of natural gas or to express these different commodities in a common unit. In calculating equivalents, we use a generally recognized standard in which one Bbl of oil is equal to six Mcf of natural gas. Also, when we refer to cubic feet measurements, all measurements are at 14.73 pounds per square inch.

When we refer to "us", "we", "our", or "ours", we are describing Colorado Interstate Gas Company and/or our subsidiaries.

PART I

ITEM 1. BUSINESS

General

We are a Delaware corporation incorporated in 1927. In January 2001, we became a wholly owned subsidiary of El Paso Corporation through the merger of a wholly owned El Paso subsidiary with The Coastal Corporation (Coastal). On June 29, 2001, all of our outstanding common stock was contributed from our former parent company, El Paso CNG Company (formerly Coastal Natural Gas Company) to Noric Holdings III L.L.C. (Noric III), a wholly owned subsidiary of El Paso. We own and operate an interstate natural gas pipeline system, natural gas processing facilities and gathering systems. We also have natural gas and oil exploration and production operations.

Segments

Our operations are segregated into two primary business segments: Pipeline and Field Services. These segments are strategic business units that provide a variety of energy products and services. We manage each segment separately, and each segment requires different marketing strategies. For information relating to operating revenues, operating income, earnings before interest and income taxes (EBIT) and identifiable assets by segment, you should see Part II, Item 8, Financial Statements and Supplementary Data, Note 9, which is incorporated herein by reference.

Pipeline Segment

Our Pipeline segment provides natural gas transmission services and consists of approximately 4,600 miles of pipeline with a design capacity of 2,928 MMcf/d. During 2001, 2000 and 1999, average throughput was 1,448 BBtu/d, 1,383 BBtu/d and 1,301 BBtu/d. Our system extends from most production areas in the Rocky Mountain region and the Anadarko Basin to the front range of the Rocky Mountains and various interconnects with pipeline systems transporting gas to the Midwest, the Southwest, California and the Pacific Northwest. We have approximately 29 Bcf of underground working gas storage capacity along our system.

In addition to our existing system, the Federal Energy Regulatory Commission (FERC) has approved the Front Range Expansion project. This project will install compression and pipeline looping to increase deliverability along the Colorado Front Range market area. Pipeline looping is the installation of a pipeline, parallel to an existing pipeline, with tie-ins at several points along the existing pipeline. Looping increases the transmission system's capacity. This project will add approximately 283 MMcf/d to our capacity and is anticipated to be completed in December 2002.

Our Pipeline segment also produces and sells natural gas and oil under contracts covering producing fields in the Panhandle region in Texas, Oklahoma and Kansas. See a discussion of our reserves on these fields under Other Operations below. The natural gas we produce is primarily sold to Pioneer Natural Resources USA, Inc., or sold at the wellhead and delivered to our interstate natural gas pipeline system. The crude oil and condensate produced are sold at the wellhead to oil purchasing companies at prevailing market prices. The production of natural gas and oil is subject to regulation in the states in which we operate. For a further discussion of our Pioneer contract, see Part II, Item 8, Financial Statements and Supplementary Data, Note 7.

Regulatory Environment

Our interstate system is regulated by the FERC under the Natural Gas Act of 1938 and the Natural Gas Policy Act of 1978. This system operates under a separate FERC approved tariff that establishes rates, terms and conditions under which it provides services to its customers. Generally, the FERC's authority extends to:

- transportation and storage of natural gas, rates and charges;
- certification and construction of new facilities;

- extension or abandonment of services and facilities;
- maintenance of accounts and records;
- relationships between pipeline and marketing affiliates;
- depreciation and amortization policies;
- acquisition and disposition of facilities; and
- initiation and discontinuation of services.

Our tariff was established through filings with the FERC, and affects our operations and our ability to recover fees for the services we provide. Generally, changes to these fees or terms of service can only be implemented upon approval by the FERC.

Our interstate pipeline system is also subject to the Natural Gas Pipeline Safety Act of 1968 that establishes pipeline safety requirements, the National Environmental Policy Act and other environmental legislation. Our system has a continuing program of inspection designed to keep our facilities in compliance with pollution control and pipeline safety requirements. We believe that our system is in compliance with the applicable requirements.

We are also subject to regulation over the safety requirements in the design, construction, operation and maintenance of our interstate transmission and storage facilities by the U.S. Department of Transportation. Operations on U.S. government land are regulated by the U.S. Department of the Interior.

For a discussion of significant rates and regulatory matters, see Part II, Item 8, Financial Statements and Supplementary Data, Note 7.

Markets and Competition

Our interstate transmission system faces varying degrees of competition from other pipelines, as well as alternative energy sources. Also, the potential consequences of proposed and ongoing restructuring and deregulation of the electric power industry are currently unclear. Restructuring and deregulation may benefit the natural gas industry by creating more demand for natural gas turbine generated electric power, or it may hamper demand by allowing a more effective use of surplus electric capacity through increased wheeling as a result of open access.

We have approximately 165 firm and interruptible customers, including natural gas producers, marketers, end users and other natural gas transmission, distribution and electric generation companies. We have approximately 160 firm transportation contracts, with remaining terms that extend from 2 months to 23 years, and with an average remaining term of 7 years. Substantially all of our firm capacity is fully subscribed. The significant customer we served during 2001 was Public Service Company of Colorado with capacity of 1,231 BBtu/d under contract until 2007.

We serve two major markets, our "on-system" market, consisting of utilities and other customers located along the front range of the Rocky Mountains in Colorado and Wyoming, and our "off-system" market, consisting of the transportation of Rocky Mountain production from multiple supply basins to interconnections with other pipelines bound for the Midwest, the Southwest, California and the Pacific Northwest. We face different types of competition in both markets. In the on-system market, competition comes from local supply in the Denver-Julesburg basin, from an intrastate pipeline directly serving Denver and from off-system shippers who can deliver their gas in that market, supplanting our transportation for on-system customers. In our "off-system" market, we face competition in our supply areas from competitors who can ship natural gas to the Midwest, California, the Southwest and Pacific Northwest.

Our ability to extend our existing contracts or re-market expiring capacity with our customers is based on a variety of factors, including competitive alternatives, the regulatory environment at the local, state and federal levels and market supply and demand factors at the relevant extension or expiration dates. While we make every attempt to re-negotiate contract terms at fully-subscribed quantities and at maximum rates allowed under their tariffs, we must, at times, discount our rates to remain competitive.

Field Services Segment

Our Field Services segment provides midstream services in the Rocky Mountain and Mid-Continent regions, including natural gas gathering, treating and processing. Our natural gas gathering and processing facilities are located throughout the production areas adjacent to our transmission system. We own and operate various gathering lines, field compressors and gathering systems which gathered 421 MMcf/d and 510 MMcf/d for the years ended December 31, 2001 and 2000.

We own and operate one natural gas processing plant which has operating capacity of 15 MMcf/d . We also have processing arrangements on three additional plants in which we pay a fee to the plant owners to have natural gas processed at these locations. The products that these plants recover include ethane, propane, isobutane, normal butane, natural gas and helium.

Regulatory Environment

Our Field Services operations are subject to the Natural Gas Pipeline Safety Act of 1968, the Hazardous Liquid Pipeline Safety Act and the National Environmental Policy Act. We have a continuing program of inspection designed to keep all of the facilities in compliance with pollution control and pipeline safety requirements, and we believe that these systems are in compliance with applicable requirements.

Markets and Competition

We compete with major integrated energy companies, independent natural gas gathering and processing companies, natural gas marketers and oil and natural gas producers in gathering and processing natural gas and natural gas liquids. Competition for throughput and natural gas supplies is based on a number of factors, including price, efficiency of facilities, gathering system line pressures, availability of facilities near drilling activity, service and access to favorable downstream markets.

Other Operations

Our Other Operations include natural gas and oil development and production in the U.S.

Natural Gas and Oil Reserves

The following table details our proved reserves for both our Pipeline segment and other production activities at December 31, 2001. All of our production activities are in the U.S.

	Net Proved Reserves[(1)]		
	Natural Gas (MMcf)	Liquids[(2)] (MBbls)	Total (MMcfe)
Pipeline segment			
Producing	182,857	97	183,439
Total proved	182,857	97	183,439
Other			
Producing	2,130	7	2,172
Non-producing	107	1	112
Undeveloped	2,326	29	2,502
Total proved	4,563	37	4,786

(1) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.
(2) Includes oil, condensate and natural gas liquids.

For a further discussion of our reserves, see Part II, Item 8, Financial Statements and Supplementary Data, Note 14.

Wells and Acreage

The following table details our gross and net interest in developed and undeveloped acreage at December 31, 2001:

	Developed		Undeveloped		Total	
	Gross	Net[1]	Gross	Net[1]	Gross	Net[1]
Pipeline Segment	262,474	259,276	—	—	262,474	259,276
Other	8,247	4,109	10,171	8,949	18,418	13,058
	270,721	263,385	10,171	8,949	280,892	272,334

[1] Net indicates our net ownership in this acreage.

Our net developed acreage is concentrated primarily in Texas (93 percent) and Oklahoma (7 percent). Approximately 1 percent and 87 percent of our total net undeveloped acreage is under leases that have minimum remaining primary terms expiring in 2002 and 2004.

The following table details our domestic productive wells at December 31, 2001:

	Gross	Net
Pipeline Segment		
Natural Gas	793	788
Oil	9	8
Total	802	796
Other		
Natural Gas	21	6
Total	21	6
Total	823	802

The following table details our development wells drilled during the years 1999 through 2001:

	2001		2000		1999	
	Gross	Net	Gross	Net	Gross	Net
Pipeline Segment						
Productive	5	5	7	1	22	13
Total	5	5	7	1	22	13
Other						
Productive	—	—	—	—	11	7
Total	—	—	—	—	11	7
Total	5	5	7	1	33	20

The information above should not be considered indicative of future drilling performance, nor should it be assumed that there is any correlation between the number of productive wells drilled and the amount of natural gas and oil that may ultimately be recovered.

Net Production, Unit Prices and Production Costs

The following table details our net production volumes, average sales prices received and average production costs associated with the sale of natural gas and oil for each of the three years ended December 31:

	2001	2000	1999
Pipeline Segment			
Natural Gas (MMcf)	30,393	33,433	35,634
Oil, Condensate and Liquids (MBbls)	16	25	24
Average Sales Price[1]			
Natural Gas ($/Mcf)	$ 3.00	$ 2.06	$ 1.38
Oil, Condensate and Liquids ($/Bbl)	$22.56	$27.79	$15.03
Other			
Natural Gas (MMcf)	1,081	3,663	5,495
Oil, Condensate and Liquids (MBbls)	13	160	80
Average Sales Price[1]			
Natural Gas ($/Mcf)	$ 4.93	$ 3.80	$ 1.93
Oil, Condensate and Liquids ($/Bbl)	$20.74	$16.12	$15.30
Average Production Cost ($/Mcfe)[2]	$ 0.59	$ 0.38	$ 0.59

(1) Includes costs associated with transporting volumes sold and the effects of our hedging program.

(2) Includes direct lifting costs (labor, repairs and maintenance, materials and supplies) and the administrative costs of field offices, insurance and property and severance taxes.

Regulatory and Operating Environment

Our natural gas and oil activities are regulated at the federal, state and local levels. These regulations include, but are not limited to, the drilling and spacing of wells, conservation, forced pooling and protection of correlative rights among interest owners. We are also subject to governmental safety regulations in the jurisdictions in which we operate.

Our production operations under federal natural gas and oil leases are regulated by the statutes and regulations of the U.S. Department of the Interior that currently impose liability upon lessees for the cost of pollution resulting from their operations. Royalty obligations on all federal leases are regulated by the Minerals Management Service, which has promulgated valuation guidelines for the payment of royalties by producers. These domestic laws and regulations relating to the protection of the environment affect our natural gas and oil operations through their effect on the construction and operation of facilities, drilling operations, production or the delay or prevention of future offshore lease sales. We believe that our operations are in compliance with the applicable requirements. In addition, we maintain insurance for sudden and accidental spills and oil pollution liability.

Our business has operating risks normally associated with drilling and production of natural gas and oil, including blowouts, cratering, pollution and fires, each of which could result in damage to life or property. Customary with industry practices, we maintain insurance coverage with respect to potential losses resulting from these operating hazards. However, insurance is not available to us against all operational risks.

Markets and Competition

The natural gas and oil business is highly competitive in the search for and acquisition of additional reserves and in the sale of natural gas, oil and natural gas liquids. Our competitors include major and intermediate sized natural gas and oil companies, independent natural gas and oil operations and individual producers or operators with varying scopes of operations and financial resources. Competitive factors include price, contract terms and quality of service. To some degree, we mitigate our price risk by hedging the cash flows from our natural gas and oil producing activities. Ultimately, our future success in the production business will be dependent on our ability to find or acquire additional reserves at costs that allow us to remain competitive.

Environmental

A description of our environmental activities is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 7, and is incorporated herein by reference.

Employees

As of March 28, 2002, we had approximately 250 full-time employees, none of whom are subject to collective bargaining agreements.

ITEM 2. PROPERTIES

A description of our properties is included in Item 1, Business, and is incorporated herein by reference.

We believe that we have satisfactory title to the properties owned and used in our businesses, subject to liens for current taxes, liens incident to minor encumbrances, and easements and restrictions that do not materially detract from the value of these properties or our interests therein or the use of these properties in our businesses. We believe that our properties are adequate and suitable for the conduct of our business in the future.

ITEM 3. LEGAL PROCEEDINGS

A description of our legal proceedings is included in Part II, Item 8, Financial Statements and Supplementary Data, Note 7, and is incorporated herein by reference.

ITEM 4. SUBMISSION OF MATTERS TO A VOTE OF SECURITY HOLDERS

Item 4, Submission of Matters to a Vote of Security Holders, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

PART II

ITEM 5. MARKET FOR THE REGISTRANT'S COMMON EQUITY AND RELATED STOCKHOLDER MATTERS

On January 29, 2001, El Paso CGP Company (formerly The Coastal Corporation) became a wholly owned subsidiary of El Paso. On June 29, 2001, all of our common stock was contributed from El Paso CNG, a subsidiary of El Paso, to Noric III. Accordingly, there is no public trading market for our common stock.

We pay dividends on our common stock from time to time from legally available funds that have been approved for payment by our Board of Directors. We paid cash dividends of $120 million and $39 million to our parent in 2001 and 2000.

ITEM 6. SELECTED FINANCIAL DATA

Item 6, Selected Financial Data, has been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

ITEM 7. MANAGEMENT'S DISCUSSION AND ANALYSIS OF FINANCIAL CONDITION AND RESULTS OF OPERATIONS

The information required by this Item is presented in a reduced disclosure format pursuant to General Instruction I to Form 10-K. The notes to consolidated financial statements contain information that is pertinent to the following analysis, including a discussion of our significant accounting policies.

Segment Results

Our business activities are segregated into two segments: Pipeline and Field Services. These segments are strategic business units that offer a variety of different energy products and services, and each requires different technology and marketing strategies. Our historical segments (natural gas systems and exploration and production) have been restated and included in the segments in which these businesses were managed and operated following the merger. All prior periods have been restated to reflect this presentation. In addition, during 2001, Field Services became a separate segment reflecting the fact that it is managed separately from our Pipeline segment. The results presented in this analysis are not necessarily indicative of the results that would have been achieved had the revised business segment structure been in place during those periods. Operating revenues and expenses by segment include intersegment revenues and expenses which are eliminated in consolidation. Because changes in energy commodity prices have a similar impact on both our operating revenues and cost of products sold from period to period, we believe that gross margin (revenue less cost of products sold) provides a more accurate and meaningful basis for analyzing operating results for our Field Services segment. For a further discussion of our individual segments, see Item 8, Financial Statements and Supplementary Data, Note 9. The following table presents earnings before interest and income taxes (EBIT) by segment and in total for each of the years ended December 31:

	2001	2000
	(In millions)	
Pipeline	$126	$159
Field Services	22	14
Segment total	148	173
Corporate and other, net	5	8
Consolidated EBIT	$153	$181

Pipeline

Our Pipeline segment operates our interstate pipeline business under a tariff that governs its operations and rates. Operating results for our pipeline system have generally been stable because the majority of the revenues are based on fixed reservation charges. As a result, we expect changes in this aspect of our business to be primarily driven by regulatory actions, system expansions and contractual events. Commodity or throughput-based revenues account for a smaller portion of our operating results. These revenues vary from period to period, and are impacted by factors such as weather, operating efficiencies, competition from other pipelines and fluctuations in natural gas prices. Results of operations of the Pipeline segment were as follows for the year ended December 31:

	2001	2000
	(In millions, except volume amounts)	
Operating revenues	$ 367	$ 338
Operating expenses	(244)	(183)
Other income	3	4
EBIT	$ 126	$ 159
Throughput volumes (BBtu/d)	1,448	1,383

Included in our results of operations for the year ended December 31, 2001, are merger-related costs of $31 million associated with El Paso Corporation's merger with The Coastal Corporation in January 2001. These costs include employee severance, retention and transition costs and costs for post-retirement benefits settled and curtailed under existing benefit plans.

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Operating revenues for the year ended December 31, 2001, were $29 million higher than the same period in 2000. The increase was due to higher transportation and storage revenues as a result of completed system expansions and new contracts during 2001, higher realized prices on company owned production and increased fuel recoveries due to higher natural gas prices and increased fuel efficiencies. The increase was partially offset by the favorable resolution of natural gas price-related contingencies in 2000.

Operating expenses for the year ended December 31, 2001, were $61 million higher than the same period in 2000. The increase was a result of merger-related costs arising from employee benefits and severance charges and other merger charges related to El Paso's merger with Coastal, increased corporate allocations and higher fuel costs resulting from higher natural gas prices.

Field Services

The Field Services segment provides midstream services in the Rockies and Mid-Continent regions, including gathering and treating of natural gas and the processing of natural gas. The gathering and treating operations earn margins substantially from fixed-fee-based services; however, some of these operations earn margins from market-based rates. Processing operations earn a margin based on make-whole contracts which allow us to retain the extracted liquid products and return to the producer a Btu equivalent amount of natural gas. Under market-based rates and make-whole contracts, Field Services may have more sensitivity to price changes during periods when natural gas and natural gas liquids prices are volatile.

Field Services' operating results and an analysis of these results are as follows for each of the years ended December 31:

	2001	2000
	(In millions)	
Gathering, treating and processing gross margin	$31	$ 30
Operating expenses	(9)	(16)
EBIT	$22	$ 14

Year Ended December 31, 2001 Compared to Year Ended December 31, 2000

Total gross margin for the year ended December 31, 2001, was $1 million higher than the same period in 2000. The increase was a result of higher volumes in 2001 due to the transfer of natural gas processing contracts from an affiliate. This transfer was due to the re-alignment of our activities as a result of our parent's merger with El Paso. The increase was partially offset by lower gathering and treating volumes due to a natural decline in natural gas reserves.

Operating expenses for the year ended December 31, 2001, were $7 million lower than the same period in 2000 due to lower general and administrative expenses.

Affiliated Interest Income, Net

Affiliated interest income, net, for the year ended December 31, 2001, was $11 million lower than the same period in 2000 primarily due to lower interest rates on advances under our cash management program with El Paso.

Income Taxes

The effective income tax rate for the years ended December 31, 2001, and 2000 was 34 percent and 36 percent. The effective tax rates were different than the statutory rate of 35 percent primarily due to state income taxes and dividends from affiliated companies. For a reconciliation of statutory rate to effective tax rate, see Item 8, Financial Statements and Supplementary Data, Note 3.

Commitments and Contingencies

For a discussion of our commitments and contingencies, see Item 8, Financial Statements and Supplementary Data, Note 7, which is incorporated herein by reference.

CAUTIONARY STATEMENT FOR PURPOSES OF THE "SAFE HARBOR" PROVISIONS OF THE PRIVATE SECURITIES LITIGATION REFORM ACT OF 1995

This report contains or incorporates by reference forward-looking statements within the meaning of the Private Securities Litigation Reform Act of 1995. Where any forward-looking statement includes a statement of the assumptions or bases underlying the forward-looking statement, we caution that, while we believe these assumptions or bases to be reasonable and in good faith, assumed facts or bases almost always vary from the actual results, and the differences between assumed facts or bases and actual results can be material, depending upon the circumstances. Where, in any forward-looking statement, we or our management express an expectation or belief as to future results, that expectation or belief is expressed in good faith and is believed to have a reasonable basis. We cannot assure you, however, that the statement of expectation or belief will result or be achieved or accomplished. The words "believe," "expect," "estimate," "anticipate" and similar expressions will generally identify forward-looking statements. Our forward-looking statements, whether written or oral, are expressly qualified by these cautionary statements and any other cautionary statements that may accompany those statements. In addition, we disclaim any obligation to update any forward-looking statements to reflect events or circumstances after the date of this report.

ITEM 7A. QUANTITATIVE AND QUALITATIVE DISCLOSURES ABOUT MARKET RISK

Interest Rate Risk

Our primary market risk is exposure to changing interest rates. The table below shows the carrying value and related weighted average interest rates of our interest bearing securities, by expected maturity dates. As of December 31, 2001, the fair value of our long-term debt has been estimated based on quoted market prices for the same or similar issues.

	December 31, 2001								December 31, 2000	
	Expected Fiscal Year of Maturity of Carrying Amounts									
	2002	2003	2004	2005	2006	Thereafter	Total	Fair Value	Carrying Amounts	Fair Value
	(Dollars in millions)									
Liabilities:										
Long-term debt, including current portion — fixed rate				$180		$100	$280	$306	$280	$299
Average interest rate				10%		6.85%				

Non-trading Commodity Price Risk

We have entered into hedging transactions to manage commodity price risk related to a portion of our natural gas production. The table below presents the hypothetical changes in fair values arising from immediate selected potential changes in the quoted market prices of derivative commodity instruments outstanding at December 31, 2001 and 2000. Gain or loss on these derivative commodity instruments would be offset by a corresponding gain or loss on the hedged commodity, which are not included in the table.

	Year End	10% Increase		10% Decrease	
	Fair Value	Fair Value	Increase/ (Decrease)	Fair Value	Increase/ (Decrease)
	(In millions)				
Impact of changes in commodity prices on derivative commodity instruments:					
2001	$ 3	$ 2	$ (1)	$ 4	$ 1
2000	$ (2)	$ (3)	$ (1)	$ (1)	$ 1

ITEM 8. FINANCIAL STATEMENTS AND SUPPLEMENTARY DATA

COLORADO INTERSTATE GAS COMPANY

CONSOLIDATED STATEMENTS OF INCOME
(In millions)

	Year Ended December 31,		
	2001	2000	1999
Operating revenues	$497	$388	$311
Operating expenses			
Operation and maintenance	262	157	120
Merger-related costs	31	—	—
Depreciation, depletion and amortization	37	35	29
Taxes, other than income taxes	17	18	16
	347	210	165
Operating income	150	178	146
Other income			
Affiliated dividend income	3	—	—
Other, net	—	3	1
	3	3	1
Income before interest, income taxes and other charges	153	181	147
Non-affiliated interest and debt expense	23	24	25
Affiliated interest income, net	(11)	(22)	(15)
Income taxes	48	65	50
	60	67	60
Net income	$ 93	$114	$ 87
Other comprehensive income	3	—	—
Comprehensive income	$ 96	$114	$ 87

See accompanying notes.

COLORADO INTERSTATE GAS COMPANY

CONSOLIDATED BALANCE SHEETS
(In millions, except share amounts)

	December 31, 2001	December 31, 2000
ASSETS		
Current assets		
Cash and cash equivalents	$ 1	$ 1
Accounts and notes receivable, net of allowance of less than $1 for 2001 and 2000		
Customer	50	61
Affiliates	280	349
Other	10	1
Materials and supplies	5	7
Deferred income taxes	11	18
Other	9	—
Total current assets	366	437
Property, plant and equipment, at cost		
Pipeline	1,321	1,151
Gathering and processing systems	151	148
Natural gas and oil properties, at full cost	164	100
	1,636	1,399
Less accumulated depreciation, depletion and amortization	818	732
Total property, plant and equipment, net	818	667
Investments in unconsolidated affiliates	29	62
Other	6	23
Total assets	$1,219	$1,189
LIABILITIES AND STOCKHOLDER'S EQUITY		
Current liabilities		
Accounts and notes payable		
Trade	$ 32	$ 19
Affiliates	10	9
Other	28	32
Taxes payable	41	15
Other	42	44
Total current liabilities	153	119
Long-term debt	280	280
Deferred income taxes	121	119
Other	26	10
Commitments and contingencies		
Minority interest	3	2
Stockholder's equity		
Common stock, no par value; authorized 10,000 shares; issued and outstanding 10 shares at stated value	28	28
Additional paid-in capital	20	19
Retained earnings	585	612
Accumulated other comprehensive income	3	—
Total stockholder's equity	636	659
Total liabilities and stockholder's equity	$1,219	$1,189

See accompanying notes.

COLORADO INTERSTATE GAS COMPANY

CONSOLIDATED STATEMENTS OF CASH FLOWS
(In millions)

	Year Ended December 31,		
	2001	2000	1999
Cash flows from operating activities			
Net income	$ 93	$114	$ 87
Adjustments to reconcile net income to net cash from operating activities			
Depreciation, depletion and amortization	37	35	29
Deferred income tax expense	9	23	7
Non-cash portion of merger-related costs	17	—	—
Working capital changes, net of non-cash transactions			
Accounts receivable	1	(13)	(7)
Accounts payable	(35)	(24)	(4)
Accounts payable/receivable with affiliates	(28)	11	(18)
Taxes payable	26	(7)	—
Other working capital changes	41	(3)	—
Non-working capital changes and other	(1)	—	—
Net cash provided by operating activities	160	136	94
Cash flows from investing activities			
Additions to property, plant and equipment	(175)	(63)	(46)
Net proceeds from the sale of assets	3	—	11
Return of capital from investments	33	—	—
Investments in unconsolidated affiliates	—	2	(4)
Net change in affiliated advances receivable	99	(34)	(54)
Net cash used in investing activities	(40)	(95)	(93)
Cash flows from financing activities			
Net change in note payable to affiliate	—	(2)	—
Dividends paid	(120)	(39)	—
Net cash used in financing activities	(120)	(41)	—
Increase in cash and cash equivalents	—	—	1
Cash and cash equivalents			
Beginning of period	1	1	—
End of period	$ 1	$ 1	$ 1

See accompanying notes.

COLORADO INTERSTATE GAS COMPANY

CONSOLIDATED STATEMENTS OF STOCKHOLDER'S EQUITY
(In millions, except share amounts)

	Common stock		Additional paid-in capital	Retained earnings	Accumulated Other Comprehensive Income	Total stockholder's equity
	Shares	Amount				
January 1, 1999	10,000	$28	$19	$ 450	—	$ 497
Net income				87		87
December 31, 1999	10,000	28	19	537	—	584
Net income				114		114
Cash dividend				(39)		(39)
December 31, 2000	10,000	28	19	612	—	659
Net income				93		93
Allocated tax benefit of El Paso equity plans			1			1
Other comprehensive income					3	3
Cash dividend				(120)		(120)
December 31, 2001	10,000	$28	$20	$ 585	$ 3	$ 636

See accompanying notes.

COLORADO INTERSTATE GAS COMPANY

NOTES TO CONSOLIDATED FINANCIAL STATEMENTS

1. Summary of Significant Accounting Policies

Basis of Presentation

Our consolidated financial statements include the accounts of all majority-owned, controlled subsidiaries after the elimination of all significant intercompany accounts and transactions. Our financial statements for prior periods include reclassifications that were made to conform to the current year presentation. Those reclassifications had no impact on reported net income or stockholder's equity.

Principles of Consolidation

We consolidate entities when we have the ability to control the operating and financial decisions and policies of that entity. Where we can exert significant influence over, but do not control, those policies and decisions, we apply the equity method of accounting. We use the cost method of accounting where we are unable to exert significant influence over the entity. The determination of our ability to control or exert significant influence over an entity involves the use of judgment of the extent of our control or influence and that of the other equity owners or participants of the entity.

Use of Estimates

The preparation of financial statements in conformity with U.S. generally accepted accounting principles requires the use of estimates and assumptions that affect the amounts we report as assets, liabilities, revenues and expenses and our disclosures in these financial statements. Actual results can, and often do, differ from those estimates.

Cash and Cash Equivalents

We consider short-term investments with an original maturity of less than three months to be cash equivalents.

Allowance for Doubtful Accounts

We establish provisions for losses on accounts receivable and for natural gas imbalances due from shippers and operators if we determine that we will not collect all or part of the outstanding balance. We review collectibility regularly and establish or adjust our allowance as necessary using the specific identification method.

Materials and Supplies

We value materials and supplies at the lower of cost or market value with cost determined using the average cost method.

Natural Gas Imbalances

Natural gas imbalances occur when the actual amount of natural gas delivered from or received by a pipeline system, processing plant or storage facility differs from the contractual amount scheduled to be delivered or received. We value these imbalances due to or from shippers and operators at an appropriate market index price based on when we expect to settle the imbalance. Imbalances are settled in cash or made up in-kind, subject to the contractual terms of settlement.

Imbalances due from others are reported in our balance sheet as either accounts receivable from customers or accounts receivable from affiliates. Imbalances owed to others are reported on the balance sheet as either trade accounts payable or accounts payable to affiliates. In addition, all imbalances are classified as current based on when we expect to settle them.

Natural Gas and Oil Properties

We use the full cost method to account for our natural gas and oil properties. Under the full cost method, all productive and nonproductive costs incurred in connection with the acquisition, exploration and development of natural gas and oil reserves are capitalized. These capitalized costs include the costs of all unproved properties, internal costs directly related to acquisition and exploration activities, and capitalized interest.

We amortize these costs using a unit of production method over the life of our proved reserves. Our total capitalized costs are limited to a ceiling based on the present value of future net revenues using current prices, discounted at 10 percent, plus the lower of cost or fair market value of unproved properties. If these discounted revenues are not equal to or greater than total capitalized costs, we are required to write-down our capitalized costs to this level. We perform a ceiling test calculation each quarter. Although we had no write-downs in the periods presented, any required write-downs would be included in our income statements as ceiling test charges. Our ceiling test calculations include the effects of derivative instruments we have designated as cash flow hedges of our anticipated future natural gas and oil production.

We do not recognize a gain or loss on sales of our natural gas and oil properties, unless the properties sold are significant. We treat sales as an adjustment to the cost of our properties.

Property, Plant and Equipment

Our property, plant and equipment is recorded at its original cost of construction or, upon acquisition, at the fair value of the assets acquired. We capitalize all direct and indirect costs of the project, including interest costs on related debt. We capitalize the major units of property replacements or improvements and expense minor items. The following table presents our property, plant and equipment by type, depreciation method, remaining useful lives and depreciation rate:

Type	Method	Remaining Useful Lives (In years)	Rates
Pipeline and storage systems	Straight-line	2-53	2% to 27%
Gathering and processing systems	Straight-line	1-40	3% to 20%
Transportation equipment	Straight-line	1-5	20% to 33%
Buildings and improvements	Straight-line	1-40	3% to 7%
Office and miscellaneous equipment	Straight-line	1-10	10% to 33%

When we retire properties, we reduce property, plant and equipment for its original cost, less accumulated depreciation, and salvage. Any remaining amount is charged to income.

At December 31, 2001 and 2000, we had approximately $25 million and $33 million of construction work in progress included in our property, plant and equipment.

Asset Impairments

We evaluate our long-lived assets for impairment in accordance with SFAS No. 121, *Accounting for the Impairment of Long-Lived Assets and for Long-Lived Assets to be Disposed Of.* If an adverse event or change in circumstances occurs, we estimate the future cash flows from the asset, grouped together at the lowest level for which separate cash flows can be measured, to determine if the asset is impaired. If the total of the undiscounted future cash flows is less than the carrying amount for the assets, we calculate the fair value of the assets either through reference to sales data for similar assets, or by estimating the fair value using a discounted cash flow approach. These cash flow estimates require us to make estimates and assumptions for many years into the future for pricing, demand, competition, operating costs, legal, regulatory and other factors, and these assumptions can change either positively or negatively.

On January 1, 2002, we adopted the provision of SFAS No. 144, *Accounting for the Impairment or Disposal of Long-Lived Assets,* which will impact how we account for asset impairments and the accounting for discontinued operations in the future.

Revenue Recognition

We recognize revenues from natural gas transportation and storage service in the period the service is provided. Our other business activities record revenues when they are earned. Revenues are earned when deliveries of physical commodities are made, or when services are provided. See the discussion of price risk management activities below for the impact on our revenues from our hedging activities.

Environmental Costs and Other Contingencies

We expense or capitalize expenditures for ongoing compliance with environmental regulations that relate to past or current operations as appropriate. We expense amounts for clean up of existing environmental contamination caused by past operations which do not benefit future periods by preventing or eliminating future contamination. We record liabilities when our environmental assessments indicate that remediation efforts are probable, and the costs can be reasonably estimated. Estimates of our liabilities are based on currently available facts, existing technology and presently enacted laws and regulations taking into consideration the likely effects of inflation and other societal and economic factors, and include estimates of associated legal costs. These amounts also consider prior experience in remediating contaminated sites, other companies' clean-up experience and data released by the Environmental Protection Agency (EPA) or other organizations. They are subject to revision in future periods based on actual costs or new circumstances and are included in our balance sheet in other current and long-term liabilities at their undiscounted amounts. We evaluate recoveries from insurance coverage, government sponsored and other programs separately from our liability and, when recovery is assured, we record and report an asset separately from the associated liability in our financial statements.

We recognize liabilities for other contingencies when we have an exposure that, when fully analyzed, indicates it is both probable that an asset has been impaired or that a liability has been incurred and the amount of impairment or loss can be reasonably estimated. Funds spent to remedy these contingencies are charged against a reserve, if one exists, or expensed. When a range of probable loss can be estimated, we accrue the most likely amount or at least the minimum of the range of probable loss.

Price Risk Management Activities

We use derivative financial instruments to hedge our cash flow exposure on our forecasted natural gas sales to changing commodity prices. These derivative financial instruments consist of primarily swap contracts that require payments to (or receipts from) counterparties based on the differences between fixed and variable commodity prices.

On January 1, 2001, we adopted the provisions of SFAS No. 133, *Accounting for Derivative Instruments and Hedging Activities,* in accounting for our derivative instruments. Under SFAS No. 133, all derivatives are reflected in our balance sheet as other current assets at their fair market value. We do not apply the mark-to-market method of accounting for contracts that qualify as normal purchases and sales under SFAS No. 133.

We designate our derivatives as cash flow hedges on the date that we enter into the derivative contract. Changes in the derivative fair values are deferred to the extent that they are effective and are recorded as a component of accumulated other comprehensive income until the hedged transactions occur and are recognized in earnings. The ineffective portion of these hedges is recognized immediately in earnings as a component of operating revenues in our income statement.

As required by SFAS No. 133, we formally document all relationships between hedging instruments and hedged items, as well as our risk management objectives, strategies for undertaking various hedge transactions and our methods for assessing and testing correlation and hedge ineffectiveness. Our derivative instruments are linked to the related hedged forecasted transaction. We also assess, both at the inception of the hedge and on an on-going basis, whether the derivatives that are used in our hedging transactions are highly effective in offsetting changes in cash flows of the hedged items. We discontinue hedge accounting prospectively if we determine that a derivative is no longer highly effective as a hedge.

The market value of these instruments reflects our best estimate and is based upon exchange quotations. Our actual results may differ from our estimates, and these differences can be positive or negative.

Cash inflows and outflows associated with the settlement of our derivatives are recognized in operating cash flows, and any receivables and payables resulting from these settlements are reported separately from the derivatives in our balance sheet as trade receivables and payables.

Prior to our adoption of SFAS No. 133, we applied hedge accounting for our derivatives only if the derivative reduced the risk of the underlying hedged item, was designated as a hedge at its inception and was expected to result in financial impacts which were inversely correlated to those of the item being hedged. If correlation ceased to exist, hedge accounting was terminated and the derivatives were recorded at their fair value in the balance sheet and changes in fair value were recorded in income. Hedging derivatives were recorded as gains or losses in operating income and cash inflows and outflows were recognized in operating cash flow only as the settlement of those transactions occurred.

Income Taxes

We report current income taxes based on our taxable income along with a provision for deferred income taxes. Deferred income taxes reflect the estimated future tax consequences of differences between the financial statement and tax bases of assets and liabilities and carryovers at each year end. We account for tax credits under the flow-through method, which reduces the provision for income taxes in the year the tax credits first become available. We reduce deferred tax assets by a valuation allowance when, based on our estimates, it is more likely than not that a portion of those assets will not be realized in a future period. The estimates utilized in the recognition of deferred tax assets are subject to revision, either up or down, in future periods based on new facts or circumstances.

El Paso maintains a tax sharing policy for companies included in its consolidated federal income tax return which provides, among other things, that (i) each company in a taxable income position will be currently charged with an amount equivalent to its federal income tax computed on a separate return basis, and (ii) each company in a tax loss position will be reimbursed currently to the extent its deductions, including general business credits, were utilized in the consolidated return. Under the policy, El Paso pays all federal income taxes directly to the IRS and bills or refunds its subsidiaries for their portion of these income tax payments. Prior to 2001, we had a tax sharing agreement with El Paso CGP Company which had similar provisions.

Accounting for Asset Retirement Obligations

In August 2001, the FASB issued SFAS No. 143, *Accounting for Asset Retirement Obligations.* This Statement requires companies to record a liability relating to the retirement and removal of assets used in their business. The liability is discounted to its present value, and the related asset value is increased by the amount of the resulting liability. Over the life of the asset, the liability will be accreted to its future value and eventually extinguished when the asset is taken out of service. The provisions of this Statement are effective for fiscal years beginning after June 15, 2002. We are currently evaluating the effects of this pronouncement.

2. Merger-Related Costs

During the year ended December 31, 2001, we incurred merger-related costs of $31 million associated with El Paso's merger with Coastal. Our merger-related costs consist of employee severance, retention and transition costs for severed employees and early retirees that occurred as a result of El Paso's merger-related workforce reduction and consolidation as well as costs for post-retirement benefits settled and curtailed under existing benefit plans. The post-retirement benefits were accrued on the merger date and will be paid over the applicable benefit periods of the terminated and retired employees. All other employee costs were expensed as incurred and have been paid. Following the merger, approximately 180 full time positions were eliminated through a combination of early retirements and terminations. Our merger-related costs also include charges relating to the valuation of natural gas imbalances to conform our imbalance valuation methods to El Paso's, the write-off of a software system that was in development and charges related to a disputed gas pricing claim.

All charges were accrued as of the merger date with the exception of the gas pricing claim which was expensed when incurred.

3. Income Taxes

The following table reflects the components of income tax expense for each of the three years ended December 31:

	2001	2000	1999
	(In millions)		
Current			
Federal	$36	$40	$40
State	3	2	3
	39	42	43
Deferred			
Federal	10	21	6
State	(1)	2	1
	9	23	7
Total income tax expense	$48	$65	$50

Our income tax expense differs from the amount computed by applying the statutory federal income tax rate of 35 percent to income before taxes for the following reasons at December 31:

	2001	2000	1999
	(In millions)		
Tax expense at the statutory federal rate of 35%	$49	$63	$48
Increase (decrease)			
State income tax, net of federal income tax benefit	1	3	3
Other	(2)	(1)	(1)
Income tax expense	$48	$65	$50
Effective tax rate	34%	36%	36%

The following are the components of our net deferred tax liability at December 31:

	2001	2000
	(In millions)	
Deferred tax liabilities		
Property, plant and equipment	$138	$129
Other	15	1
Total deferred tax liability	153	130
Deferred tax assets		
Reserve for rate refund and contested claims	10	15
Employee benefits and deferred compensation obligations	7	—
Other	26	14
Total deferred tax asset	43	29
Net deferred tax liability	$110	$101

Under El Paso's tax sharing policy, we are allocated the tax benefit associated with our employees' exercise of non-qualified stock options and the vesting of restricted stock as well as restricted stock dividends. This allocation reduced taxes payable by $1 million in 2001. These benefits are included in additional paid-in capital in our balance sheet.

4. Financial Instruments

Fair Value of Financial Instruments

As of December 31, 2001, and 2000, the carrying amounts of cash and cash equivalents, short-term borrowings, and trade receivables and payables are representative of fair value because of the short-term maturity of these instruments. We estimated the fair value of debt with fixed interest rates based on quoted market prices for the same or similar issues.

The carrying amounts and estimated fair values of our financial instruments are as follows at December 31:

	2001		2000	
	Carrying Amount	Fair Value	Carrying Amount	Fair Value
	(In millions)			
Balance sheet financial instruments:				
Long-term debt, including current maturities	$280	$306	$280	$299
Other financial instruments:				
Non-Trading instruments(1)				
Commodity swap contracts	$ 3	$ 3	$ —	$ (2)

(1) On January 1, 2001, we adopted SFAS No. 133. Under SFAS No. 133, all derivative instruments are recorded at their fair value in our financial statements.

5. Accounting for Hedging Activities

On January 1, 2001, we adopted the provisions of SFAS No. 133 and recorded a cumulative unrealized loss of $2 million, net of income taxes, in accumulated other comprehensive income to recognize the fair value of all derivatives designated as cash flow hedging instruments. As of December 31, 2001, the value of cash flow hedges included in accumulated other comprehensive income was an unrealized gain of $3 million, net of income taxes. We estimate that this amount will be reclassified to earnings during the next twelve months. Events that will cause this reclassification relate to the sale of energy commodities. These deferred amounts, once reclassified into earnings will offset currently anticipated sales of commodities and will produce a determinable cash flow stream.

For the year ended December 31, 2001, no ineffectiveness was recorded in earnings on our cash flow hedges.

6. Long-Term Debt

Our long-term debt outstanding consisted of the following at December 31:

	2001	2000
	(In millions)	
10% Senior Debentures, due 2005	$180	$180
6.85% Senior Debentures, due 2037	100	100
	280	280
Long-term debt, less current maturities	$280	$280

Aggregate maturities of the principal amounts of long-term debt for the next 5 years and in total thereafter are as follows:

	(In millions)
2002	$ —
2003	—
2004	—
2005	180
2006	—
Thereafter	100
Total long-term debt, including current maturities	$ 280

Other Financing Arrangement

During 1999, El Paso formed a series of companies referred to as Clydesdale. Clydesdale was formed to provide financing to invest in various capital projects and other assets. The proceeds are collateralized by various fixed assets, including our transmission system.

7. Commitments and Contingencies

Legal Proceedings

In 1997, we and a number of our affiliates were named defendants in actions brought by Jack Grynberg on behalf of the U.S. Government under the False Claims Act. Generally, these complaints allege an industry-wide conspiracy to under report the heating value as well as the volumes of the natural gas produced from federal and Native American lands, which deprived the U.S. Government of royalties. These matters have been consolidated for pretrial purposes (In re: Natural Gas Royalties *Qui Tam* Litigation, U.S. District Court for the District of Wyoming, filed June 1997). In May 2001, the court denied the defendants' motions to dismiss.

We and a number of our affiliates were named defendants in *Quinque Operating Company, et al v. Gas Pipelines and Their Predecessors, et al*, filed in 1999 in the District Court of Stevens County, Kansas. This class action complaint alleges that the defendants mismeasured natural gas volumes and heating content of natural gas on non-federal and non-Native American lands. The Quinque complaint was transferred to the same court handling the Grynberg complaint and has now been sent back to Kansas State Court for further proceedings. A motion to dismiss this case is pending.

In addition, we and our subsidiaries and affiliates are named defendants in numerous lawsuits and governmental proceedings that arise in the ordinary course of our business. For each of these matters, we evaluate the merits of the case, our exposure to the matter and possible legal or settlement strategies and the likelihood of an unfavorable outcome. If we determine that an unfavorable outcome is probable and can be estimated, we make the necessary accruals. As new information becomes available, our estimates may change. The impact of these changes may have a material effect on our results of operations. As of December 31, 2001, we had reserves totaling $19 million for all outstanding legal matters.

While the outcome of the matters discussed above cannot be predicted with certainty, based on information known to date, as well as our existing accruals, we do not expect the ultimate resolution of these matters to have a material adverse effect on our ongoing financial position, operating results or cash flows.

Environmental Matters

We are subject to extensive federal, state and local laws and regulations governing environmental quality and pollution control. These laws and regulations require us to remove or remedy the effect on the environment of the disposal or release of specified substances at current and former operating sites. As of December 31, 2001, we had a reserve of approximately $7 million for expected remediation costs. In addition, we expect to make capital expenditures for environmental matters of approximately $1 million in the aggregate for the years 2002 through 2006. These expenditures primarily relate to compliance with clean air regulations.

It is possible that new information or future developments could require us to reassess our potential exposure related to environmental matters. We may incur significant costs and liabilities in order to comply with existing environmental laws and regulations. It is also possible that other developments, such as increasingly strict environmental laws and regulations and claims for damages to property, employees, other persons and the environment resulting from our current or past operations, could result in substantial costs and liabilities in the future. As this information becomes available, or other relevant developments occur, we will adjust our accrual amounts accordingly. While there are still uncertainties relating to the ultimate costs we may incur, based upon our evaluation and experience to date, we believe the recorded reserves are adequate.

Rates and Regulatory Matters

In March 2001, we filed a rate case with the FERC proposing increased rates of $9 million annually and new and enhanced services for our customers. This filing was required under the settlement of our 1996 general rate case. We received an order from the FERC in late April 2001, which suspended the rates until October 1, 2001, subject to refund, and subject to the outcome of an evidentiary hearing. On September 26, 2001, the FERC issued an order rejecting two firm services we had proposed in our rate filing and required us to reallocate the costs allocated to those two services to existing services. We have complied with this order and have arranged with the affected customers to provide service under existing rate schedules. The evidentiary hearing was suspended pending ongoing attempts to settle the case.

In September 2001, the FERC issued a Notice of Proposed Rulemaking (NOPR). The NOPR proposes to apply the standards of conduct governing the relationship between interstate pipelines and marketing affiliates to all energy affiliates. The proposed regulations, if adopted by the FERC, would dictate how all our energy affiliates conduct business and interact with our interstate pipelines. We cannot predict the outcome of the NOPR, adoption of the regulations in substantially the form proposed would, at a minimum, place additional administrative and operational burdens on us.

While we cannot predict with certainty the final outcome or the timing of the resolution of our rate and regulatory matters, we believe the ultimate resolution of these issues, based on information known to date, will not have a material adverse effect on our financial position, results of operations or cash flows.

Capital Commitments

At December 31, 2001, we had capital and investment commitments of $139 million primarily related to our Panhandle, Front Range Expansion and Valley Line Enhancements projects. Our other planned capital and investment projects are discretionary in nature, with no substantial capital commitments made in advance of the actual expenditures.

Operating Leases

We lease property, facilities and equipment under various operating leases. The aggregate minimum lease commitments are $2 million for the years 2002 to 2006 with immaterial annual operating lease payments thereafter. These amounts exclude minimum annual commitments paid by El Paso, which are allocated to us through an overhead allocation. Rental expense on our operating leases for the years ended December 31, 2001, 2000 and 1999 was $3 million, $5 million and $5 million.

Other

We executed a service agreement with Wyoming Interstate Company, Ltd., our affiliate, providing for the availability of pipeline transportation capacity through July 31, 2007. Under the service agreement, we are required to make minimum payments on a monthly basis with minimum annual payments of $9 million per year for 2002 through 2004 and $3 million per year for 2005 through 2006, and $2 million thereafter. We expensed approximately $9 million, $9 million and $5 million for the years ended December 31, 2001, 2000 and 1999 related to this agreement.

We are party to an agreement, known as the Amarillo "B" Contract, under which we are obligated to sell to Pioneer Natural Resources USA, Inc. (Pioneer) 77 percent of the cumulative natural gas production from specified acreage in the Panhandle Field of Texas. The remaining production is being sold to other parties. The agreement remains in effect for as long as the acreage remains commercially productive. In the event that the acreage becomes commercially unproductive and Pioneer has not received its 77 percent, we will be required to make a cash payment to Pioneer for such make-up volume on a price equal to the higher of our net sales proceeds from this field or a value based on a spot market index. Based on reserve reports prepared by Huddleston & Co., Inc., an independent reserve engineering firm, we have not fully produced our 23 percent share of the total estimated Panhandle Field reserves.

8. Retirement Benefits

Pension and Retirement Benefits

El Paso maintains a pension plan to provide benefits as determined by a cash balance formula covering substantially all of its U.S. employees, including our employees. Also, El Paso maintains a defined contribution plan covering its U.S. employees, including our employees. El Paso matches 75 percent of participant basic contributions of up to 6 percent, with matching contributions made in El Paso common stock, which participants may diversify at any time. El Paso is responsible for benefits accrued under its plan and allocates the related costs to its affiliates. See Note 12 for a summary of transactions with affiliates.

Prior to our merger with El Paso, Coastal provided non-contributory pension plans covering substantially all of its U.S. employees, including our employees. On April 1, 2001, this plan was merged into El Paso's existing plan. Our employees who were participants in this plan on March 31, 2001 receive the greater of cash balance benefits under the El Paso plan or Coastal's plan benefits accrued through March 31, 2006.

Other Postretirement Benefits

As a result of El Paso's merger with Coastal, we offered a one-time election through an early retirement window for employees who were at least age 50 with 10 years of service on December 31, 2000, to retire on or before June 30, 2001 and keep benefits under our postretirement medical and life plans. The costs associated with the curtailment and special termination benefits were $8 million. Medical benefits for this closed group of retirees may be subject to deductibles, co-payment provisions, and other limitations and dollar caps on the amount of employer costs. El Paso has reserved the right to change these benefits. Employees who retire on or after June 30, 2001, will continue to receive limited postretirement life insurance benefits. Our postretirement benefit plan costs are pre-funded to the extent such costs are recoverable through rates.

In January 2001, following the merger, we changed the measurement date for measuring our other postretirement benefit obligations from December 31 to September 30. We made this change to conform our measurement date to the date that El Paso uses to measure other postretirement benefit obligations. The new method is consistent with the manner in which El Paso gathers other postretirement information and will facilitate ease of planning and reporting in a more timely manner. We believe this method is preferable to the method previously employed. We accounted for this as a change in accounting principle, and it had no material effect on retirement benefit expense for the current or prior periods.

The following table sets forth the change in benefit obligation, change in plan assets, reconciliation of funded status, and components of net periodic benefit cost for other postretirement benefits as of and for the twelve months ended December 31, 2000 and September 30, 2001:

	2001	2000
	(In millions)	
Change in postretirement benefit obligation		
Benefit obligation at beginning of period	$ 15	$ 15
Interest cost	1	1
Participant contributions	1	—
Plan amendment	(2)	—
Curtailment and special termination benefits	3	—
Actuarial gain	(2)	—
Benefits paid	(1)	(1)
Postretirement benefit obligation at end of period	$ 15	$ 15
Change in plan assets		
Fair value of plan assets at beginning of period	$ 10	$ 10
Employer contributions	1	1
Benefits paid	(1)	(1)
Fair value of plan assets at end of period	$ 10	$ 10
Reconciliation of funded status		
Funded status at end of period	$ (5)	$ (5)
Fourth quarter contributions	1	—
Unrecognized actuarial gain	(3)	(4)
Unrecognized transition obligation	—	10
Prepaid (accrued) postretirement benefits at December 31	$ (7)	$ 1

	Year Ended December 31,		
	2001	2000	1999
	(In millions)		
Postretirement benefit costs include the following components			
Interest cost	$1	$1	$1
Amortization of transition obligation	—	1	1
Curtailment and special termination benefits	8	—	—
Net postretirement benefit cost	$9	$2	$2

Postretirement benefit obligations are based upon actuarial estimates as described below:

	2001	2000
Weighted average assumptions		
Discount rate	7.25%	7.75%
Expected return on plan assets	7.50%	4.60%

Actuarial estimates for our postretirement benefits plans assume a weighted average annual rate of increase in the per capita costs of covered health care benefits of 9.5 percent in 2001, gradually decreasing to 6 percent by the year 2008. Assumed health care cost trends have a significant effect on the amounts reported for other postretirement benefit plans. The impact of a one-percentage point change in assumed health care cost trends would have been less than $1 million for both our service and interest costs and our accumulated postretirement benefit obligations.

9. Segment Information

Our business activities are segregated into two distinct operating segments: Pipeline and Field Services. These segments are strategic business units that provide a variety of energy products and services. They are managed separately as each business unit requires different technology and marketing strategies. We measure segment performance using earnings before interest and income taxes (EBIT). Our historical segments (natural gas systems and exploration and production) have been restated and included in the segments in which these businesses were managed and operated following the merger. All prior periods have been restated to reflect this presentation. In addition, during 2001, Field Services became a separate segment reflecting the fact that it is managed separately from our Pipeline segment. The following are our results as of and for the years ended December 31:

	Year Ended December 31, 2001			
	Pipeline	Field Services	Other(1)	Total
		(In millions)		
Revenues from external customers	$ 366	$ 125	$ 6	$ 497
Intersegment revenues	1	1	(2)	—
Merger-related costs	31	—	—	31
Depreciation, depletion and amortization	35	2	—	37
Operating income	123	22	5	150
Other income	3	—	—	3
Earnings before interest and income taxes	126	22	5	153
Assets	1,108	78	33	1,219
Capital expenditures and investments in unconsolidated affiliates	172	3	—	175
Total investments in unconsolidated affiliates	—	—	29	29

	Year Ended December 31, 2000			
	Pipeline	Field Services	Other(1)	Total
		(In millions)		
Revenues from external customers	$ 338	$30	$20	$ 388
Depreciation, depletion and amortization	28	2	5	35
Operating income	155	14	9	178
Other income (expense)	4	—	(1)	3
Earnings before interest and income taxes	159	14	8	181
Assets	1,104	53	32	1,189
Capital expenditures and investments in unconsolidated affiliates	58	3	2	63
Total investments in unconsolidated affiliates	33	—	29	62

	Year Ended December 31, 1999			
	Pipeline	Field Services	Other(1)	Total
		(In millions)		
Revenues from external customers	$ 271	$28	$12	$ 311
Depreciation, depletion and amortization	21	2	6	29
Operating income	134	11	1	146
Other income	1	—	—	1
Earnings before interest and income taxes	135	11	1	147
Assets	1,089	53	44	1,186
Capital expenditures and investments in unconsolidated affiliates	35	5	6	46
Total investments in unconsolidated affiliates	35	—	29	64

(1) Includes our eliminations and natural gas and oil activities.

The reconciliations of EBIT to net income are presented below.

	For the Year Ended December 31, 2001	2000	1999
	(In millions)		
Total EBIT for segments	$153	$181	$147
Non-affiliated interest and debt expense	23	24	25
Affiliated interest income, net	(11)	(22)	(15)
Income tax expense	48	65	50
Net income	$ 93	$114	$ 87

10. Transactions with Major Customers

The following table shows revenues from major customers for each of the three years ended December 31:

	2001[1]	2000	1999
	(In millions)		
Public Service Company of Colorado	$97	$85	$87
Pioneer Natural Resources USA, Inc.	64	49	36

11. Supplemental Cash Flow Information

The following table contains supplemental cash flow information for each of the three years ended December 31:

	2001	2000	1999
	(In millions)		
Interest paid	$22	$25	$25
Income tax payments	13	49	44

12. Investments in and Transactions with Related Parties

The following table shows investments in affiliates for each of the three years ended December 31:

	Ownership Interest	2001	2000	1999
		(In millions)		
Coastal Medical Services, Inc.	—%	$ —	$ 33	$ 35
Coastal Limited Ventures, Inc.	4%	14	14	14
Coastal Oil and Gas Resources, Inc.	4%	15	15	15
Total		$ 29	$ 62	$ 64

In 1996, Coastal Medical Services Inc. was formed to improve the value of Coastal's medical benefit program for its employees and employees of its subsidiaries by managing the medical obligations of its participating subsidiaries. Coastal Medical Services was created through the contribution of cash by 25 El Paso CGP subsidiaries in exchange for Coastal Medical Services stock. We accounted for the investment using the cost method since we did not have ability to exert significant influence over operating or managing decisions of Coastal Medical Services. In December 2001, we redeemed our 4 percent ownership interest in Coastal Medical Services and recorded dividend income of $3 million.

In 1999, we transferred a production payment and the properties burdened by the production payment to Coastal Limited Ventures, Inc. and Coastal Oil and Gas Resources Inc., two separate subsidiaries of Coastal, in exchange for a 4 percent interest in the common stock of each subsidiary. We accounted for the exchange at historical cost since it occurred between entities under common control. We accounted for the investment in each of the affiliated companies using the cost method since we did not have the ability to exert significant influence over their operating or management decisions. The total investment was $29 million as of December 2001 and 2000.

We participate in El Paso's cash management program which matches short-term cash surpluses and needs of its participating affiliates, thus minimizing total borrowing from outside sources. We had advanced $232 million at December 31, 2001, at a market rate of interest which was 2.1%. At December 31, 2000, we had advanced $331 million at a market rate of interest which was 7.3%.

At December 31, 2001 and 2000, we had accounts receivable from affiliates of $48 million and $18 million. In addition, we had accounts payable to affiliates of $10 million and $9 million at December 31, 2001 and 2000. These balances were incurred in the normal course of our business.

El Paso allocated a portion of its general and administrative expenses to us in 2001. The allocation is based on the estimated level of effort devoted to our operations and the relative size of our revenues, gross property and payroll. We believe the allocation methods are reasonable. In 2000 and 1999, we performed most of our own administrative functions and provided some administrative functions for our affiliates. As a result, our allocated administrative expenses were lower and our reimbursement of costs were higher than in 2001.

Beginning after the merger in 2001, we entered into transactions with other El Paso subsidiaries in the ordinary course of our business to transport, sell and purchase natural gas which increased our affiliated revenue and charges. Services provided by these affiliates for our benefit are based on the same terms as non-affiliates.

The following table shows revenues and charges from our affiliates for each of the three years ended December 31:

	2001	2000	1999
Revenues	$191	$89	$68
Charges	106	16	13
Reimbursement for costs	1	7	10

13. Supplemental Selected Quarterly Financial Information (Unaudited)

Financial information by quarter is summarized below.

Quarter	Operating Revenues	Operating Income	Net Income
		(In millions)	
2001			
1st	$125	$ 47	$ 29
2nd	132	18	10
3rd	118	38	22
4th	122	47	32
	$497	$150	$ 93
2000			
1st	$ 93	$ 50	$ 31
2nd	84	32	20
3rd	79	25	16
4th	132	71	47
	$388	$178	$114

14. Supplemental Natural Gas and Oil Operations (Unaudited)

For purposes of the Supplemental Natural Gas and Oil Operations disclosure, we have presented reserves, the standardized measure of discounted future net cash flows and the related changes in standardized measure separately for our Pipeline segment's production activities. The Supplemental Natural Gas and Oil

Operations disclosure does not include any value for the Pipeline segment storage gas and liquids volumes managed by our pipeline segment.

Capitalized costs relating to natural gas and oil producing activities and related accumulated depreciation, depletion and amortization were as follows at December 31:

	2001	2000
	(In millions)	
Natural gas and oil properties:		
Costs subject to amortization	$163	$ 99
Costs not subject to amortization	1	1
	164	100
Less accumulated DD&A	163	96
Net capitalized costs	$ 1	$ 4

During the years ended December 31, 2001, 2000 and 1999, we incurred costs in our natural gas and oil producing activities, substantially all of which were development costs, of less than $1 million, $2 million and $6 million. In addition, as of December 31, 2001, 2000 and 1999, we had less than $1 million in capitalized acquisition costs that were not being amortized in our full cost pool. The majority of these costs are expected to be included in the amortization calculation in the years 2002 through 2004. Total amortization expense per Mcfe was $1.03, $1.015, and $0.87 in 2001, 2000, and 1999.

Net quantities of proved developed and undeveloped reserves of natural gas and liquids, including condensate and crude oil, and changes in these reserves are presented below. All of our proved properties are located in the United States.

	Natural Gas		Liquids[1]	
	Pipeline Segment	Other	Pipeline Segment	Other
	(Bcf)		(MBbls)	
Net proved developed and undeveloped reserves[2]				
January 1, 1999	212	113	237	550
Revisions of previous estimates	22	(100)	36	(330)
Extensions, discoveries and other	—	1	—	19
Purchases of reserves in place	—	—	—	—
Sales of reserves in place	—	—	—	—
Production	(36)	(5)	(24)	(80)
December 31, 1999	198	9	249	159
Revisions of previous estimates	11	5	7	110
Extensions, discoveries and other	—	—	—	—
Purchases of reserves in place	—	—	—	—
Sales of reserves in place	—	(1)	—	—
Production	(33)	(4)	(25)	(160)
December 31, 2000	176	9	231	109
Revisions of previous estimates	37	(3)	(118)	(59)
Extensions, discoveries and other	—	—	—	—
Purchases of reserves in place	—	—	—	—
Sales of reserves in place	—	—	—	—
Production	(30)	(1)	(16)	(13)
December 31, 2001	183	5	97	37
Proved developed reserves				
December 31, 1999	198	7	249	140
December 31, 2000	176	6	231	81
December 31, 2001	183	2	97	8

(1) Includes oil, condensate and natural gas liquids.

(2) Net proved reserves exclude royalties and interests owned by others and reflects contractual arrangements and royalty obligations in effect at the time of the estimate.

There are numerous uncertainties inherent in estimating quantities of proved reserves and in projecting future rates of production and timing of development expenditures, including many factors beyond our control. The reserve data represents only estimates. Reservoir engineering is a subjective process of estimating underground accumulations of natural gas and oil that cannot be measured in an exact manner.

Results of operations from producing activities by fiscal year were as follows:

	Year Ended December 31,		
	2001	2000	1999
	(In millions)		
Net revenues:			
Sales to external customers	$ 3	$15	$ 3
Affiliated sales	3	1	9
Total	6	16	12
Production costs	(1)	(3)	(5)
Depreciation, depletion and amortization	—	(4)	(5)
	5	9	2
Income tax (expense) benefit	(2)	(3)	1
Results of operations for producing activities (excluding corporate overhead and interest costs)	$ 3	$ 6	$ 3

The standardized measure of discounted future net cash flows relating to proved natural gas and oil reserves follows at December 31:

	2001		2000		1999	
	Pipeline Segment	Other	Pipeline Segment	Other	Pipeline Segment	Other
	(In millions)					
Future cash inflows	$313	$ 14	$ 474	$ 53	$229	$20
Future production and development costs	(64)	(3)	(110)	(7)	(74)	(7)
Future income tax (expenses) benefits	(83)	17	(116)	(10)	(49)	3
Future net cash flows	166	28	248	36	106	16
10% annual discount for estimated timing of cash flows	(72)	(9)	(89)	(10)	(41)	(2)
Standardized measure of discounted future net cash flows	$ 94	$ 19	$ 159	$ 26	$ 65	$14

For the calculations in the preceding table, estimated future cash inflows from estimated future production of proved reserves were computed using year-end market natural gas and oil prices. We may receive amounts different than the standardized measure of discounted cash flow for a number of reasons, including changes in prices, the amounts realized based on our hedging strategies and changes in production or reserve estimates.

We do not rely upon the standardized measure when making investment and operating decisions. These decisions are based on various factors including probable and proved reserves, different price and cost assumptions, actual economic conditions and corporate investment criteria.

The following are the principal sources of change in the standardized measure of discounted future net cash flows:

	2001		2000		1999	
	Pipeline Segment	Other	Pipeline Segment	Other	Pipeline Segment	Other
	(In millions)					
Sales and transfers of oil and gas produced net of production costs	$(255)	$ (5)	$(52)	$(15)	$(36)	$ (8)
Net changes in prices and production costs	10	(15)	150	10	(6)	13
Extensions, discoveries and improved recovery, less related costs	—	—	—	—	—	1
Changes in estimated future development costs	13	1	—	—	—	—
Development costs incurred during the period	—	—	—	—	—	2
Revisions of previous quantity estimates	39	(5)	34	25	28	(56)
Accretion of discount	23	3	4	—	7	5
Net change in income taxes	25	16	(42)	(8)	3	8
Change in production rates, timing and other	80	(2)	—	—	—	—
Net change	$ (65)	$ (7)	$ 94	$ 12	$ (4)	$(35)

REPORT OF INDEPENDENT ACCOUNTANTS

To the Board of Directors and Stockholder of
El Paso Colorado Interstate Gas Company:

In our opinion, the consolidated financial statements in the Index appearing under Item 14 (a) (1) present fairly, in all material respects, the consolidated financial position of Colorado Interstate Gas Company as of December 31, 2001, and the consolidated results of its operations and its cash flows for the year then ended in conformity with accounting principles generally accepted in the United States of America. In addition, in our opinion, the financial statement schedule listed in the index under Item 14 (a) (2) presents fairly, in all material respects, the information set forth therein when read in conjunction with the related consolidated financial statements. These financial statements and the financial statement schedule are the responsibility of the Company's management; our responsibility is to express an opinion on these financial statements and the financial statement schedule based on our audit. We conducted our audit of these statements in accordance with auditing standards generally accepted in the United States of America, which require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements, assessing the accounting principles used and significant estimates made by management, and evaluating the overall financial statement presentation. We believe that our audit provides a reasonable basis for our opinion.

As discussed in Notes 1 and 5, the Company adopted Statement of Financial Accounting Standards No. 133, Accounting for Derivative Instruments and Hedging Activities, on January 1, 2001.

As discussed in Note 14, the Company changed the measurement date used to account for postretirement benefits other than pensions from December 31 to September 30.

We also audited the adjustments described in Note 15 that were applied to restate the disclosures of 2000 and 1999 segment information in the accompanying financial statements to give retroactive effect to the change in reportable segments. In our opinion, such adjustments are appropriate and have been properly applied to the prior period financial statements.

PricewaterhouseCoopers LLP

Houston, Texas
March 6, 2002

INDEPENDENT AUDITORS' REPORT

Board of Directors and Stockholder
Colorado Interstate Gas Company
Colorado Springs, Colorado

We have audited the consolidated balance sheets of Colorado Interstate Gas Company (an indirect, wholly owned subsidiary of El Paso CGP Company, formerly The Coastal Corporation) and subsidiaries as of December 31, 2000, and the related consolidated statements of operations, stockholders' equity and cash flows for each of the two years in the period ended December 31, 2000. These financial statements are the responsibility of the Company's management. Our responsibility is to express an opinion on these financial statements based on our audits.

We conducted our audits in accordance with auditing standards generally accepted in the United States of America. Those standards require that we plan and perform the audit to obtain reasonable assurance about whether the financial statements are free of material misstatement. An audit includes examining, on a test basis, evidence supporting the amounts and disclosures in the financial statements. An audit also includes assessing the accounting principles used and significant estimates made by management, as well as evaluating the overall financial statement presentation. We believe that our audits provide a reasonable basis for our opinion.

In our opinion, such consolidated financial statements present fairly, in all material respects, the consolidated financial position of Colorado Interstate Gas Company and subsidiaries as of December 31, 2000, and the results of their operations and their cash flows for each of the two years in the period ended December 31, 2000, in conformity with accounting principles generally accepted in the United States of America.

/s/ Deloitte & Touche LLP

Denver, Colorado
February 23, 2001

SCHEDULE II

COLORADO INTERSTATE GAS COMPANY

VALUATION AND QUALIFYING ACCOUNTS
Years Ended December 31, 2001, 2000 and 1999
(In millions)

Description	Balance at Beginning of Period	Charged to Costs and Expenses	Charged to Other Accounts	Deductions	Balance at End of Period
2001					
Legal Reserves	$22	$ —	$ (3)	$—	$19
Environmental Reserves	4	—	3	—	7
Regulatory Reserves	—	5	—	—	5
2000					
Legal Reserves	$42	$(17)[1]	$ (3)	$—	$22
Environmental Reserves	1	—	3	—	4
1999					
Legal Reserves	$42	$ —	$ —	$—	$42
Environmental Reserves	1	—	—	—	1

[1] Includes reversal of $16 million of legal reserves due to the favorable resolution of natural gas price-related contingencies.

ITEM 9. CHANGES IN AND DISAGREEMENTS WITH ACCOUNTANTS ON ACCOUNTING AND FINANCIAL DISCLOSURE

None.

PART III

Item 10, "Directors and Executive Officers of the Registrant;" Item 11, "Executive Compensation;" Item 12, "Security Ownership of Management;" and Item 13, "Certain Relationships and Related Transactions," have been omitted from this report pursuant to the reduced disclosure format permitted by General Instruction I to Form 10-K.

PART IV

ITEM 14. EXHIBITS, FINANCIAL STATEMENT SCHEDULES, AND REPORTS ON FORM 8-K

(a) The following documents are filed as part of this report:

1. Financial statements and supplemental information.

The following consolidated financial statements are included in Part II, Item 8, of this report:

2. Financial statement schedules.

Schedules other than that listed above are omitted because they are not applicable.

(b) Reports on Form 8-K.

None.

COLORADO INTERSTATE GAS COMPANY

EXHIBIT LIST
December 31, 2001

Exhibits not incorporated by reference to a prior filing are designated by an asterisk. All exhibits not so designated are incorporated herein by reference to a prior filing as indicated.

Exhibit Number	Description
*3.A	— Amended and Restated Certificate of Incorporation dated as of March 7, 2002.
*3.B	— By-Laws dated March 7, 2002.
*18	— Letter regarding Change in Accounting Principle
*99.1	— Report of Independent Accountants, PricewaterhouseCoopers LLP
*99.2	— Independent Auditors' Report, Deloitte & Touche LLP

Reports on Form 8-K

None.

Undertaking

We hereby undertake, pursuant to Regulation S-K, Item 601(b), paragraph (4)(iii), to furnish to the Securities and Exchange Commission upon request all constituent instruments defining the rights of holders of our long-term debt and our consolidated subsidiaries not filed herewith for the reason that the total amount of securities authorized under any of such instruments does not exceed 10 percent of our total consolidated assets.

SIGNATURES

Pursuant to the requirements of Section 13 or 15(d) of the Securities Exchange Act of 1934, as amended, Colorado Interstate Gas Company has duly caused this report to be signed on its behalf by the undersigned, thereunto duly authorized on the 28th day of March 2002.

COLORADO INTERSTATE GAS COMPANY

By /s/ JOHN W. SOMERHALDER II

John W. Somerhalder II
Chairman of the Board

Pursuant to the requirements of the Securities Exchange Act of 1934 as amended, this report has been signed below by the following persons on behalf of Colorado Interstate Gas Company and in the capacities and on the dates indicated:

Signature	Title	Date
/s/ JOHN W. SOMERHALDER II (John W. Somerhalder II)	Chairman of the Board, Chief Executive Officer and Director (Principal Executive Officer)	March 28, 2002
/s/ PATRICIA A. SHELTON (Patricia A. Shelton)	President and Director	March 28, 2002
/s/ GREG G. GRUBER (Greg G. Gruber)	Senior Vice President, Chief Financial Officer and Treasurer (Principal Financial and Accounting Officer)	March 28, 2002